

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Revenues

	Three months ended September 30				Nine months ended September 30			
			\$	%			\$	%
<i>(Canadian dollars in millions)</i>	2011	2010	Change	Change	2011	2010	Change	Change
Transmission	379	376	3	1	1,067	1,002	65	6
Distribution	990	970	20	2	2,998	2,795	203	7
Other	15	14	1	7	47	47	-	-
	1,384	1,360	24	2	4,112	3,844	268	7
Average Ontario 60-minute peak demand (MW) ¹	23,018	24,812	(1,794)	(7)	21,765	22,119	(354)	(2)
Distribution - units distributed to customers (TWh) ¹	7.1	7.2	(0.1)	(1)	22.0	21.6	0.4	2

¹ System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations and, therefore, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and to secondary use of our land rights-of-way.

Our transmission revenues were higher by \$3 million, or 1%, in the third quarter, and by \$65 million, or 6%, in the first nine months compared to the same periods last year. These increases were primarily due to higher tariff revenues of \$24 million in the third quarter and \$67 million year-to-date resulting from a December 23, 2010 Ontario Energy Board (OEB) decision on the 2011 and 2012 transmission rate application by our subsidiary, Hydro One Networks Inc. (Hydro One Networks). The decision followed extensive oral and written reviews of evidence we submitted for the funding necessary to support our system requirements. The resulting rates, which were effective January 1, 2011, will support our investments to address aging critical infrastructure, supply mix objectives for generation including off-coal initiatives, and the initiation of investments in support of the Green Energy Act (GEA).

The average monthly peak demand was lower for both the quarter and the year-to-date periods, resulting in a decrease in transmission revenue of \$19 million and \$8 million, respectively. Among other factors, we experienced cooler weather in the third quarter compared to 2010. For the year-to-date period, the lower demand in the third quarter was partially offset by higher demand in the first quarter of the year due to colder weather over the winter months compared to the same period in the prior year.

We experienced lower transmission revenues associated with OEB-approved deferral accounts of \$7 million in the quarter and \$9 million on a year-to-date basis, mainly related to the full recovery of a transmission regulatory account at the end of last year. We also experienced slightly higher OEB-approved export service revenue of \$1 million in the quarter and \$3 million in the year-to-date period. Ancillary revenue for the period was higher by \$4 million in the quarter and \$12 million year-over-year due to higher external revenues approved as part of the OEB rate decision. Export service revenues and external revenues received in excess of approved levels are recorded in a regulatory deferral account.

Distribution

Distribution revenues include our distribution tariff, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our approved distribution tariffs. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

Distribution revenues increased by \$20 million, or 2%, in the third quarter, and by \$203 million, or 7%, in the first nine months compared to the same periods last year. This increase reflects the recovery of higher purchased power costs of \$12 million in the third quarter and \$121 million in the first nine months, as described below under "Purchased Power."

After considering purchased power costs, increases in revenue reflect two OEB decisions on the distribution tariff rates of our subsidiary, Hydro One Networks. On April 9, 2010, the OEB approved new tariff rates effective May 1, 2010 and on December 21, 2010, the OEB approved new tariff rates effective January 1, 2011. Both OEB decisions followed extensive written and oral reviews of the evidence we submitted for the maintenance and investment requirements of our distribution system. The combined impact of these decisions was an increase in distribution revenues of \$12 million during the third quarter and \$83 million in the first nine months. These tariff rate increases enable the safe and reliable delivery of electricity to our customers throughout Ontario and the development of the Smart Grid to ensure the future of our system by facilitating the connection of new generation. We also experienced increased other revenues of \$4 million in the year-to-date period as a result of these OEB decisions.

These distribution revenue increases were partially offset by lower energy consumption of \$4 million in the third quarter, resulting primarily from the milder weather experienced in the summer compared to last year. However, on a year-to-date basis, higher consumption stemming primarily from the colder winter resulted in an increase in distribution revenue of \$3 million.

We also experienced a revenue reduction of \$8 million on a year-to-date basis associated with the full recovery of a distribution-related regulatory account effective April 30, 2010.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and comprise the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on time-of-use billing, both of which are adjusted twice annually. We began transitioning our RPP customers to time-of-use billing May 1, 2010 and the majority of our RPP customers are now on time-of-use billing. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP for the reporting and comparative periods is provided below.

Summary of RPP

Effective Date	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
	Residential	Non-Residential	First Tier	Second Tier
November 1, 2009	1,000	750	5.8	6.7
May 1, 2010	600	750	6.5	7.5
November 1, 2010	1,000	750	6.4	7.4
May 1, 2011	600	750	6.8	7.9

RPP Time-of-Use Effective Date	Rates (cents/kWh)		
	On-Peak	Mid-Peak	Off-Peak
May 1, 2010	9.9	8.0	5.3
November 1, 2010	9.9	8.1	5.1
May 1, 2011	10.7	8.9	5.9

Purchased power costs increased in 2011 by \$12 million, or 2%, to \$650 million in the third quarter and by \$121 million, or 7% to \$1,956 million in the first nine months compared to the same periods last year. The increases in our purchased power costs were primarily due to: the impact of changes in the OEB's RPP rates for residential and other eligible customers of \$20 million in the third quarter and \$67 million in the year-to-date period; higher purchased power costs for customers who are not eligible for the RPP of \$18 million in the quarter and \$40 million in the first nine months of the year; and increased transmission charges due to the OEB's transmission rate decision effective January 1, 2011 of \$6 million for the quarter and \$18 million for the year-to-date period. The effect of these increases was partially offset by the impact of lower demand for

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

electricity of \$29 million in the quarter and \$2 million in the year-to-date period, and lower charges levied by the IESO of \$3 million in the third quarter and \$2 million for the first nine months of 2011.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

	Three months ended September 30				Nine months ended September 30			
			\$	%			\$	%
(Canadian dollars in millions)	2011	2010	Change	Change	2011	2010	Change	Change
Transmission	115	90	25	28	325	300	25	8
Distribution	158	147	11	7	455	432	23	5
Other	14	16	(2)	(13)	44	45	(1)	(2)
	287	253	34	13	824	777	47	6

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by \$25 million, or 28%, in the quarter and by \$25 million, or 8%, on a year-to-date basis, compared to the same periods last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program requirements were higher by \$17 million in the quarter and by \$27 million on a year-to-date basis compared to the same periods last year. During both periods we incurred expenditures related to the Ontario Power Authority's (OPA) recommendation to increase short circuit and/or transformer capacity at 10 of our transmission stations to enable the connection of small renewable projects, for which recovery is restricted (see Future Capital Expenditures). For the nine-month period, we experienced higher requirements for planned and demand-based corrective station maintenance for power equipment and higher requirements related to the fire at our Richview Transformer Station. Our crews worked tirelessly to rebuild and in-service the impacted aging transformers to ensure adequate supply to critical local distribution companies. In addition, an increased focus on our environmental on-site oil leak reduction program reflects our priority on environmental stewardship. We also experienced higher forestry program expenditures as resources were utilized early in the year to advance the program due to favourable weather conditions. Expenditures in support of our transmission system increased by \$8 million in the quarter due to a re-allocation of resources and higher expenditures consistent with generating higher external revenues approved as part of the OEB rate decision, which also impacted the year-to-date period. Support expenditures decreased by \$2 million in the first nine months primarily due to cost management reduction initiatives related to administrative and organizational costs as well as lower expenditures related to reduced telecom costs from lower long distance rates associated with leveraging broader public sector rates on voice domain and lower data usage.

Distribution

Operation, maintenance and administration expenditures incurred to sustain our low-voltage distribution system increased by \$11 million, or 7%, in the quarter and by \$23 million, or 5%, on a year-to-date basis, compared to the respective periods last year. Our work program expenditures were slightly higher by \$4 million in the quarter and \$9 million on a year-to-date basis compared to the same periods last year. We experienced higher expenditures in the year-to-date period related to increased power restoration expenditures as the province experienced a higher volume of storm activity. In addition, we experienced increased requirements in both periods associated with unplanned system changes to implement OEB code amendments impacting the billing system. These increases were partially offset by lower expenditures in the quarter for our line patrol program as a result of new data collection methods and by lower forestry expenditures in the first nine months resulting from a re-direction of work earlier in the year. Expenditures in support of our distribution system increased by \$7 million in the quarter and \$14 million on a year-to-date basis resulting from a redirection of resources, partly offset by lower telecom costs in the year-to-date period.

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

Depreciation and Amortization

Depreciation and amortization expense increased by \$2 million, or 1%, to \$152 million in the third quarter and by \$14 million, or 3%, to \$447 million in the first nine months compared to the same periods last year. These increases were mainly attributable to higher depreciation of approximately \$5 million in the quarter and \$18 million in the first nine months of the year related to our placement of new assets in service, consistent with our ongoing capital work program. In the quarter, we experienced a decrease of \$1 million as a result of a reduction in fixed asset removals associated with our capital project work. However, in the year-to-date period, this was more than offset by increased fixed asset removal requirements associated with storm restoration and fire restoration work earlier in the year, resulting in an increase of approximately \$4 million. Amortization of regulatory and other assets declined by \$2 million in the quarter and \$8 million in the first nine months of the year, mainly due to the full recovery of a distribution regulatory account during the second quarter of last year.

Financing Charges

Financing charges increased by \$6 million, or 7%, to \$88 million in the third quarter and by \$3 million, or 1%, to \$258 million for the year-to-date period compared to the prior year. The increases were primarily due to increased interest expense of \$4 million in the quarter and \$8 million in the first nine months associated with a higher average level of debt, partially offset in the year-to-date period by a lower average effective interest rate. In the quarter, we also experienced higher charges of \$3 million, primarily related to the change in market value of our long-term investment in Province of Ontario Floating Rate Notes. The increase in our financing charges was partially offset by higher capitalized interest of \$1 million and \$5 million in the third quarter and first nine months, respectively, reflecting higher levels of construction-in-progress consistent with our growing capital program.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by \$21 million, or 111%, to \$40 million in the third quarter and by \$54 million, or 104%, to \$106 million on a year-to-date basis, compared to last year. These increases were primarily due to changes in net temporary differences, including lower capital cost allowance claimed on software than in the prior year. Higher pre-tax income in the year-to-date period also contributed to the year-over-year increase. Net increases in 2011 were partially offset by a reduction in the statutory tax rate from 31.00% to 28.25%, and by lower pre-tax income in the quarter.

Net Income

Net income of \$167 million in the third quarter was lower than our comparable 2010 results by \$51 million, or 23%. Net income of \$521 million year-to-date was higher than the prior year by \$29 million, or 6%. Net income for both periods reflected OEB rate decisions that allowed for, among other things, the recovery of assets from prior years that are now in-service. New assets in service include new investments to address our aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives, and investments in support of the GEA. Higher revenues were partially offset in the first nine months and more than offset in the quarter by higher operating expenditures including those related to our work to increase short circuit and/or transformer capacity at some of our transmission stations to enable the connection of small renewable projects and by a higher effective tax rate.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from December 31, 2009 through September 30, 2011. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

<i>(Canadian dollars in millions)</i>	2011				2010			2009
Quarter ended	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sep. 30	Jun. 30	Mar. 31	Dec. 31
Total revenue ¹	1,384	1,268	1,460	1,280	1,360	1,165	1,319	1,207
Net income ¹	167	142	212	99	218	105	169	111
Net income to common shareholder ¹	163	137	208	94	214	100	165	106

¹ The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, other investing activities, and dividends.

Summary of Sources and Uses of Cash

<i>(Canadian dollars in millions)</i>	Three months ended September 30		Nine months ended September 30	
	2011	2010	2011	2010
Operating activities	500	414	1,074	958
Financing activities				
Long-term debt issued	300	500	600	1,500
Long-term debt retired	-	-	(250)	(400)
Short-term notes payable	-	-	-	(55)
Dividends paid	(42)	(4)	(126)	(23)
Investing activities				
Capital expenditures	(382)	(401)	(1,022)	(1,106)
Long-term investment	-	-	-	(250)
Other financing and investing activities	11	12	24	31
Net change in cash and cash equivalents	387	521	300	655

Operating Activities

Net cash from operating activities increased by \$86 million, to \$500 million in the third quarter, and by \$116 million to \$1,074 million in the first nine months, compared to 2010. The increase in the quarter was attributable to changes in accounts receivable balances related to revenue levels resulting from changes in demand and OEB decisions on tariff rates, as well as changes to certain regulatory account balances. This increase was partially offset by lower net income compared to the prior year. On a year-to-date basis, the increase was primarily due to changes in certain regulatory account balances and higher net income compared to prior year.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program under which we are authorized to issue up to \$1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holding of Province of Ontario Floating Rate Notes.

The Commercial Paper Program is supported by a total of \$1,500 million in liquidity facilities comprised of our \$1,250 million committed revolving credit facility with a syndicate of banks maturing in June 2014 and our holding of \$250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

As at September 30, 2011, we had \$8,125 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2011 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. On August 23, 2011, we filed a base shelf prospectus to renew our Medium-Term Note Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program is \$3,000 million, of which \$2,700 million remains available until September 2013.

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

Rating Agency	Rating	
	Short-term Debt	Long-term Debt
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all these covenants and limitations as at September 30, 2011.

In the first nine months of 2011, we issued \$600 million in long-term debt under our MTN Program, \$300 million in the first quarter and \$300 million in the third quarter. We repaid \$250 million in maturing long-term debt, all in the first quarter. In the first nine months of 2010, we issued \$1,500 million in long-term debt under our MTN Program, including \$500 million in the third quarter, and made repayments of \$400 million in maturing long-term debt, all in the second quarter. In the first nine months of 2011, we did not issue any short-term notes and there were no short-term notes outstanding as at September 30, 2011. In the first nine months of 2010, we reduced our short-term notes by \$55 million, all in the first quarter.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Consistent with the comparative periods in the prior year, we paid preferred dividends of about \$4 million to the Province of Ontario (Province) in the third quarter and \$13 million in the first nine months. We also paid common dividends of \$38 million in the third quarter and \$113 million in the first nine months of this year. In the first nine months of 2010, we paid common dividends of \$10 million, all in the first quarter.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, we target to maintain an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

	Three months ended September 30				Nine months ended September 30			
			\$	%			\$	%
(Canadian dollars in millions)	2011	2010	Change	Change	2011	2010	Change	Change
Transmission	210	234	(24)	(10)	571	638	(67)	(11)
Distribution	172	165	7	4	450	465	(15)	(3)
Other	-	2	(2)	(100)	1	3	(2)	(67)
	382	401	(19)	(5)	1,022	1,106	(84)	(8)

Transmission

Transmission capital expenditures decreased by \$24 million, or 10%, to \$210 million in the third quarter, and decreased by \$67 million, or 11%, to \$571 million in the nine-month period, compared to the same periods in 2010.

Investments to expand and reinforce our transmission system were \$106 million in the quarter and \$289 million for the nine-month period of this year, representing reductions of \$34 million and \$59 million over the respective comparable periods. The majority of our expenditures were made on inter-area network projects to support the Province's supply mix objectives

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

for generation, although we continue to make significant investments on load customer connection and local area supply projects to address growing loads. The year-over-year reduction in our expenditures results from a few major projects that are coming to completion or others that were completed in 2010. Projects that are nearing completion include the installation of static var compensators (SVCs) at our Nanticoke and Detweiler transformer stations and at our Porcupine and Kirkland Lake transformer stations. Major inter-area network projects completed and put into service last year included the installation of capacitor banks in Southwestern Ontario and our Cherrywood Transformer Station to Claireville Transformer Station Connection Project. Local area supply projects that were substantially completed in the first quarter of last year included our GTA West Transmission Reinforcement Project and our Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection. The impact of the reductions in expenditures in both periods was partially offset by an increase in our investments this year in a number of load customer connection projects.

Inter-area network upgrades with significant expenditures this year included our Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. We are currently commissioning and testing the SVCs at our Nanticoke and Detweiler transformer stations. In the short term, this project will support increased generation from the Bruce Nuclear facility and in the longer term it will enhance the transfer capability between Southwestern Ontario and the Greater Toronto Area. In addition, we are currently in the commissioning stages of installing an SVC at our Kirkland Lake Transformer Station as part of our project to install SVCs at our Porcupine and Kirkland Lake transformer stations. This project will increase the North-South interface transfer capability to access available northern generation.

Our local area supply project expenditures include investments in our Woodstock Area Transmission Reinforcement Project to increase capacity and ensure supply reliability in the Woodstock area and the Switchyard Reconstruction Project at our Burlington Transformer Station, which will address aging infrastructure and increase the load supply capacity to ensure reliability of supply to customers in the area. During the quarter, we also commenced work on our Midtown Electricity Infrastructure Renewal project (formerly the Midtown Toronto Project), together with Toronto Hydro-Electric System Limited, to replace aging cable and overhead line facilities and to provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west.

Capital expenditures to sustain our existing transmission system were \$85 million in the quarter and \$246 million on a year-to-date basis, representing an increase of \$3 million in the quarter and a reduction of \$9 million in the nine-month period compared to prior year. The reduction for the year-to-date period was primarily related to lower lines expenditures, particularly for wood pole replacement and breaker installations, as a result of resources being re-directed to emergency restoration work within the Distribution Business. We also incurred lower expenditures for work on our protection and control systems compared to the prior year due to a re-allocation of resources to development projects and lower expenditures to enhance security infrastructure related to the prevention of copper theft as work is now nearing completion. These reductions were partially offset by higher emergency restoration work related to the July 10, 2011 forest fire in Northwestern Ontario, where crews put in a tremendous effort to replace damaged structures and restore power to mining operations and a number of First Nation communities. Our other transmission capital expenditures were \$19 million in the quarter and \$36 million for the nine-month period, representing increases of \$7 million in the quarter and \$1 million year-to-date over the comparative periods.

Distribution

Distribution capital expenditures increased by \$7 million, or 4%, to \$172 million in the third quarter and decreased by \$15 million, or 3%, to \$450 million for the nine-month period, compared to the same periods in the prior year.

Capital investments to expand and reinforce our distribution network were \$74 million in the quarter and \$204 million year-to-date, representing reductions of \$19 million and \$51 million over the comparable periods. We experienced reductions in both periods related to the substantial completion of smart meter installations by the end of 2010. Also contributing to the reductions are lower expenditures due to a re-allocation of resources to storm restoration efforts as well as lower expenditures in our wholesale metering program. During the year, we continued to invest in our smart meter network infrastructure and the development and integration of the systems required for time-of-use billing, including meter reading capability and integration with the IESO meter data repository. Of our 1.3 million customers with smart meters installed as at September 30, 2011, we had over 1.1 million consuming power based on time-of-use pricing. We also continued to invest in our Smart Grid Program that will enhance our operations and support distributed generation.

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

Expenditures to sustain our distribution system were \$57 million in the quarter and \$170 million year-to-date, representing increases of \$6 million and \$16 million compared to the same periods last year. During both periods, we experienced increased requirements for emergency restoration work as a result of a higher number of storms, including two major storms that hit Ontario in the second quarter. Partially offsetting these impacts were lower expenditures related to wood pole replacements, as resources were re-directed to storm restoration work, and reduced work related to joint use and relocation of our lines. Our other distribution capital expenditures were \$41 million in the quarter and \$76 million year-to-date, respectively representing increases of \$20 million in both periods. This increase is primarily attributable to expenditures for the next phase of our entity-wide information system replacement and improvement project related to our Customer Information System (CIS).

Future Capital Expenditures

Our capital expenditures in 2011 are budgeted at approximately \$1.8 billion. The 2011 capital budgets for our Transmission and Distribution businesses are about \$1,050 million and \$750 million, respectively. Capital expenditures are expected to be approximately \$1.8 billion in each of 2012 and 2013. These expenditures reflect the sustainment requirements of our aging infrastructure, budgeted at approximately \$550 million in 2011, \$700 million in 2012 and \$950 million in 2013. Development projects, including Smart Grid, inter-area network upgrades that reflect supply mix policies, local area supply requirements and requirements to enable distributed generation, are budgeted at approximately \$950 million in 2011, \$750 million in 2012 and \$600 million in 2013. These development investments also reflect customer demand work, distributed generation connections and the rollout of Smart Grid. Other budgeted capital expenditures amount to approximately \$300 million in 2011, \$350 million in 2012 and \$250 million in 2013. These expenditures include the replacement of our customer billing system to address end-of-life requirements and to further productivity realization from our entity-wide SAP platform. Our capital expenditures for 2011 are expected to be lower than budget by approximately \$300 million, primarily due to changes in the cost and timing of certain large transmission projects, as well as lower Distributed Generation capital expenditures as a result of higher than anticipated generator-funded investments and lower anticipated expansion and renewable enabling investments which are funded primarily by the Company.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work for specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy. The estimated capital expenditures associated with these projects and upgrades to the system are anticipated to be up to approximately \$700 million over a period to the in-service dates of these projects. On February 28, 2011, the OEB amended Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy to the OEB. The licence amendment requires Hydro One Networks to develop and seek approvals for these projects in accordance with recommendations from the OPA. In a letter dated April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at 10 of 15 transformer stations noted in the licence to accommodate small scale renewable generation. The overall capital cost for the 10 stations provided by the OPA in its April 7 letter is estimated to be approximately \$50 million and the projected in-service dates range from August 2011 to June 2012. On June 30, 2011, we received a letter from the OPA recommending the scope and timing to reconductor two circuits between Sarnia to London, the West of London Transmission Upgrade Project, to enable the connection of approximately 300-500 MW of additional renewable generation in the west of London area with a required in-service date of December 2014. On October 3, 2011, we received a letter from the OPA recommending the scope and timing of the Southwestern Ontario Reactive Compensation Priority Project, formerly the Southwestern Ontario Series Compensation Project. After consideration of the options, the OPA has recommended that we install an SVC at our Milton Switching Station to increase the capability of the Bruce transmission system. We are awaiting an OPA recommendation regarding the construction of a new transmission line west of the City of London.

In accordance with the Memorandum of Agreement between Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the Shareholder) and our Company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. Specifically, the rights, powers and duties of our Company's Directors have been restricted with regard to any decisions regarding: the pursuit of cost recovery by Hydro One Networks from microFIT and small-scale (capacity allocation exempt) FIT generation projects or proponents thereof for costs related to investment and expenditures made, or required to be made, by Hydro One Networks in order to appropriately fund the upgrades at up to 15 transformer stations pursuant to the February 28, 2011 licence condition amendment made to Hydro One Networks' transmission licence; the pursuit of cost recovery by Hydro One Networks of such costs through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates; and whether or not to pursue and implement, internal cost recovery or cost mitigation measures designed to offset the costs associated with the upgrades, and to pursue further cost minimization strategies and to increase overall cost efficiencies within our Company.

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

including the timing of any such decisions. In 2011, we anticipate spending approximately \$25 million on these projects, which would be charged to results of operations. The after-tax impact on results of operations would be approximately \$18 million.

In August 2010, the OEB introduced competition for transmission expansion projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansion under the OEB's competitive framework. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates, with the exception of the 10 transformer station upgrades noted above.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

<i>September 30, 2011 (Canadian dollars in millions)</i>	Total	2011¹	2012/2013	2014/2015	After 2015
Contractual Obligations (due by year)					
Long-term debt – principal repayments	8,125	250	1,200	1,300	5,375
Long-term debt – interest payments	6,760	141	773	655	5,191
Inergi LP (Inergi) outsourcing agreement ²	453	35	269	149	-
Operating lease commitments	51	2	15	9	25
Environmental obligations ³	379	9	61	73	236
Total Contractual Obligations	15,768	437	2,318	2,186	10,827
Other Commercial Commitments (by year of expiry)					
Bank line ⁴	1,250	-	-	1,250	-
Letters of credit ⁵	114	113	1	-	-
Guarantees ⁵	326	326	-	-	-
Pension ⁶	195	33	162	-	-
Total Other Commercial Commitments	1,885	472	163	1,250	-

¹ The amounts disclosed represent the balances due over the period October 1, 2011 to December 31, 2011.

² On May 1, 2010, we extended our Master Services Agreement with Inergi for a further three-year period. The term of the agreement, which would otherwise have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

³ We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands, as well as asset retirement obligations for the removal of asbestos-contaminated material from our facilities and the decommissioning and removal of our switching station located at Ontario Power Generation's Abitibi Canyon Generating Station. The expenditure pattern reflects our planned work programs for the periods.

⁴ As a backstop to our commercial paper program, we have a \$1,250 million revolving standby credit facility with a syndicate of banks that matures in June 2014.

⁵ We currently have outstanding bank letters of credit of \$113 million relating to retirement compensation arrangements (RCAs). The other \$1 million included in letters of credit pertains to operating letters of credit. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of \$325 million and on behalf of two distributors using guarantees of up to a maximum of \$660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

⁶ Contributions to the pension fund are made one month in arrears. Contributions for 2011 are based on an actuarial valuation filed in September 2010 and effective December 31, 2009. Our annual pension contributions for 2011 and 2012 will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we estimate our minimum pension contributions to be approximately \$145 million in 2011 and \$149 million in 2012 based on the expected level of pensionable earnings. Contributions for 2013 will be based on a new actuarial valuation effective December 31, 2012.

The amounts in the above table under long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

outsourcing agreement with Inergi are recorded under operation, maintenance and administration expense on our Statement of Operations or within our capital expenditures. Expenditures related to our environmental programs and asset retirement obligations are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation. In January 2010, we purchased \$250 million of Province of Ontario Floating Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Pension

During the first nine months of 2011, the deferred pension asset reported on our Consolidated Balance Sheet increased by \$5 million to \$465 million. We contributed \$116 million into our pension plan and incurred \$111 million in net periodic pension benefit cost. Contributions for 2011 and 2012 are based on an actuarial valuation effective December 31, 2009 that was filed in September of 2010. Based on current factors, we currently estimate our annual pension contributions to be approximately \$145 million in 2011 and \$149 million in 2012 based on the projected level of pensionable earnings. Contributions for 2013 will be based on an actuarial valuation effective December 31, 2012 and will depend on future investment returns, changes in benefits and actuarial assumptions.

Our pension plan experienced a negative return of 2.24% in the first nine months of this year, consistent with levels experienced in the current financial market. The pension fund has broad exposure from its investments in domestic and international equity markets, as well as in fixed income markets. The overall exposure of the fund reflects its holdings across a number of sectors, and a well-diversified portfolio to support long-term objectives.

We continue to monitor our financial risks, including credit risk.

STATUS OF OUR TRANSITION TO UNITED STATES (US) GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (GAAP)

Accounting Framework for External Reporting

We previously planned to adopt International Financial Reporting Standards (IFRS) effective January 1, 2012 with comparative restatement of our 2011 results. In the absence of a definitive International Accounting Standards Board (IASB) plan to provide guidance on rate-regulated accounting, we began evaluating the option of adopting US GAAP in lieu of IFRS in the first quarter of this year. On July 7, 2011, we filed our application with the Ontario Securities Commission (OSC) for exemptive relief from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* that would otherwise require us to file our consolidated financial statements based on IFRS starting with reporting periods commencing after January 1, 2012. Our application requested approval to instead adopt US GAAP, without becoming a Securities and Exchange Commission registrant, for our 2012, 2013 and 2014 fiscal years. This was approved by the OSC on July 21, 2011, and the requested exemptive relief was granted. Ontario Regulation 395/11 requires that Hydro One prepare its Consolidated Financial Statements in accordance with US GAAP for financial years on or after January 1, 2012. Our Board of Directors has approved a resolution authorizing us to report under US GAAP.

Under US GAAP, our financial reporting will be more stable and comparable with our current Canadian GAAP results than it would have been under IFRS. The use of US GAAP will also facilitate benchmarking to other large North American utilities in terms of our securities, as well as facilitate transmission cost comparisons for the OEB. Our March 31, 2012 Consolidated Financial Statements will be prepared based on US GAAP with two years of comparative restatement. Our opening US GAAP Consolidated Balance Sheet as at January 1, 2010 will be based on a retrospective application of US GAAP. As a

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

result of this decision, our IFRS conversion project efforts have been reduced. However, our work will be managed in such a way that it can effectively be restarted if a future transition to IFRS is required.

In anticipation of OSC approval of our application, we initiated a US GAAP conversion project that consists of three phases: scoping and diagnostic; analysis; and implementation. The scoping and diagnostic phase of our project involved a high level review of the major differences between existing Canadian and US GAAP. We completed this phase in the second quarter. We also substantially completed the second or analytical phase of our project in the quarter. This phase involved assessment of the impacts of adopting US GAAP on our consolidated financial statements, including measurement, classification, presentation and disclosure. The major differences identified to date include a change to the presentation of preferred shares on the balance sheet and adjustments related to accounting for employee future benefits costs. Our preferred shares, which are held entirely by the Province of Ontario, will be classified as mezzanine equity under US GAAP. In accordance with OEB rate orders, pension costs are recorded under Canadian GAAP when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs will be recorded in the same way under US GAAP. Employee future benefits other than pension are, and will continue to be recorded on an accrual basis. There are minor differences between Canadian and US GAAP for certain employee future benefits costs. However, we do not expect any significant change to the net asset position on our Consolidated Balance Sheet. Nor do we expect significant impacts on our Consolidated Statement of Operations following the application of US GAAP to our employee future benefits costs.

Over the remainder of this year, we will continue to assess and refine the impact that the conversion will have upon our disclosures.

Accounting Framework for Rate Making

Coincident with our OSC application, on July 15, 2011, we applied to the OEB for permission to adopt US GAAP instead of modified IFRS as the basis for our future rate applications and for our ongoing regulatory accounting and reporting for the Distribution Business of our subsidiary Hydro One Networks. On the same date, we also tabled a motion with the OEB requesting that it approve a variance to its December 23, 2010 decision on the transmission revenue requirement and rates of Hydro One Networks. The motion proposed that the OEB approve the use of US GAAP in place of modified IFRS for rate-setting purposes effective January 1, 2012 and that our approved 2012 transmission revenue requirement be reduced to reflect differences between US GAAP and modified IFRS with respect to those overhead and indirect costs that qualify for capitalization. For procedural reasons, on August 25, 2011, the OEB denied our motion. Instead, the OEB commenced a written proceeding to consider adjustments to our 2012 transmission revenue requirement and other adjustments and deferral and variance accounts that may be necessary should we receive OEB approval to use US GAAP for regulatory purposes. This does not change the nature of our request, merely the process the OEB intends to follow to assess it. We anticipate receiving an OEB decision on our transmission request to adopt US GAAP prior to December 31, 2011.

Debt Covenants

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. As part of our US GAAP transition, we have analyzed the impact of potential accounting changes on our debt covenants. Based on the work performed in phases one and two of our project, after conversion to US GAAP we expect to remain in compliance with these covenants. We have also amended our bond indentures allowing us to use US GAAP for external reporting purposes.

Internal Control over Financial Reporting and Disclosure Controls and Procedures

We have assessed the impact of conversion from Canadian GAAP to US GAAP on our internal controls over financial reporting and on our disclosure controls and procedures. We do not anticipate any changes to existing controls or a need for additional controls as a result of conversion.

Financial Reporting Expertise

Given the similarities between US GAAP and current Canadian GAAP, our US GAAP training efforts are focused on specific areas of difference between the two accounting frameworks and these efforts are initially being targeted to specific staff. In the fourth quarter of this year and in the first quarter of 2012, additional formal training will be provided to other finance and operational staff who are not directly involved in our conversion project. In addition, training will be provided to the Audit and Finance Committee of our Board of Directors as well as to senior executive management. This training will

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

concentrate on communicating the key differences between Canadian and US GAAP at a level of detail that is appropriate to meet their respective needs.

Information Technology (IT) Systems

We have completed a preliminary assessment of the impacts from converting to US GAAP on our IT systems. Our recently implemented SAP enterprise systems allow for flexibility in the application of accounting policies and, given the similarities between Canadian and US GAAP, we anticipate that any required IT system changes to accommodate US GAAP will be comparatively minimal. Our systems have been designed to be sufficiently flexible as to allow the future adoption of IFRS should this be required.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Our Supply Chain Enhancement Project to develop an operating framework that outlines the strategy and objectives of supply chain was implemented in the second quarter. The resulting new processes have been reviewed to assess the impact on the control environment. Process documents are updated and controls will be tested for design and operating effectiveness throughout the remainder of this year.

In an effort to optimize our customer service operations, we have initiated our CIS Project. CIS will replace two applications currently in use to provide billing, customer contact, field services, settlements and customer choice administration to our distribution customers and key constituents. The project was approved in the second quarter. The CIS project is currently in the final stages of the design phase which will be followed by the build phase. During the design phase, CIS processes and current control documentation are being reviewed and analyzed to ensure that key risks remain adequately addressed by our internal controls. Process and control documentation will continue to be updated during the build phase of the project, as key controls are tested.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the interim period ended September 30, 2011, together with other financial information included in our quarterly securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our Company is made known within our Company. Further, our Certifying Officers have also certified that internal controls over financial reporting have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

RECENT DEVELOPMENTS

Southwestern Ontario Reactive Compensation Project

On October 3, 2011, the OPA issued a letter providing us with the scope and timing of one of the three projects specified in the December 22, 2010 letter from the Minister of Energy on our amended transmission licence. The OPA has recommended that we proceed to add an SVC to the 500 kV voltage level at our Milton Switching Station to increase the capability of the Bruce transmission system. The SVC is anticipated to be in-service by the spring of 2015.

Oshawa Area Transformer Station

On October 3, 2011, the OPA issued a letter recommending that we develop an implementation plan, and initiate the necessary work for, installing additional 500-230 kV auto-transformer capacity within the east GTA as early as the spring of 2015.

Bruce to Milton Transmission Reinforcement Project

On September 14, 2011, the Niagara Escarpment Commission issued our Development Permit for the Bruce to Milton Reinforcement Project, allowing us to immediately proceed with necessary work on the Niagara Escarpment portion of the Bruce to Milton line.

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

Debt Issue

On September 26, 2011, we issued \$300 million of 30-year notes at a coupon rate of 4.39% and with a maturity date of September 26, 2041. In total, in the first nine months of the year, we have successfully raised \$600 million of cost-effective debt financing through our MTN Program.

Distribution System Code (DSC) Exemption

On October 11, 2011, the OEB issued its decision pertaining to an application we filed on April 19, 2011 requesting an exemption from the timelines in the DSC related to the connection of micro-embedded generation facilities. The decision increases the timeline for processing indirect connections that require a site assessment from 15 days to 30 days. The OEB also approved amendments to the conditions that must be met before we are required to connect micro-embedded generation facilities to the distribution system. Connections must now be performed within 5 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to with the customer. The exemption expires on April 11, 2012.

Rate Applications

On September 15, 2011, our subsidiary Hydro One Brampton Networks Inc. filed its application for 2012 rates on the basis of the OEB's third generation IRM process.

For procedural reasons, on August 25, 2011, the OEB denied Hydro One Networks' Motion to Vary the 2012 transmission rate Decision for the impacts of adopting US GAAP. However, the OEB on its own motion commenced a written proceeding to consider adjustments to our transmission revenue requirement and other adjustments and variance accounts that may be necessary should we receive approval to use US GAAP for regulatory purposes. We anticipate to receive an OEB decision on our request to adopt US GAAP prior to December 31, 2011.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended September 30		Nine months ended September 30	
	2011	2010	2011	2010
<i>(Canadian dollars in millions) (except as otherwise noted)</i>				
Net income	167	218	521	492
Net cash from operating activities	500	414	1,074	958
Capital expenditures	382	401	1,022	1,106
Basic and fully diluted earnings per common share <i>(Canadian dollars)</i>	1.626	2.134	5.077	4.790
Earnings coverage ratio ¹			2.55	2.45
Net asset coverage on long-term debt ²			1.78	1.77
Total debt to capitalization ³			56%	57%

¹ The earnings coverage ratio has been presented for the twelve months ended September 30, 2011 and September 30, 2010, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

² The net asset coverage on long-term debt ratio has been presented as at September 30, 2011 and December 31, 2010 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

³ Total debt to capitalization ratio has been presented as at September 30, 2011 and December 31, 2010 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy related revenues and profit; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including the impacts of decisions from the OEB and other governing bodies; statements related to the status of our applications to the OEB; expectations regarding revenue from our rates including the application of such revenues; statements regarding our future liquidity and capital resource and

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

operating requirements; expectations regarding our financing activities; expectations regarding the results of our on-going and planned projects and/or initiatives, their expected completion dates and expected benefits; statements regarding future capital expenditures, budgets, our investment plans, project costs and expected impacts on operations; statements related to smart meters and the associated smart grid; statements regarding contractual obligations and other commercial commitments; statements about our outsourcing arrangement with Inergi LP; statements regarding the amount and timing of future estimated environmental expenditures; statements regarding future pension contributions and our pension plan and actuarial valuation; statements about IFRS and IASB and planned courses of action; statements regarding US GAAP, planned courses of action and expected impacts on our disclosures, internal controls and systems; and statements related to our debt covenants. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and "continue", and variations of such words and similar expressions, are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; the current application of Canadian GAAP for rate-regulated activities will generally be consistent with US GAAP; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to our memorandum of agreement with it;
- the risk that unexpected capital expenditures may be needed to support renewable generation or resolve unforeseen technical issues;
- on-going discussions with the OPA regarding transmission project needs and priorities and distributed generation requirements;
- any opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- investment returns, changes in benefits or actuarial assumptions;
- the risk associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- unanticipated changes in our costs;
- the potential for substantial and currently undetermined or underestimated environmental costs and liabilities or that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the result of regulatory decisions regarding our accounting framework for rate making;
- the risks associated with changes in interest rates;
- the risks associated with current economic uncertainty and financial market volatility;

HYDRO ONE INC.**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**

- the impact of the GEA on our company and the costs and expenses arising there from; and
- the impact of increased competition on our transmission business.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in the 2010 annual Management's Discussion and Analysis (MD&A). You should review the section entitled "Risk Management and Risk Factors" in detail.

This MD&A is dated as at November 10, 2011. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)

	Three months ended September 30		Nine months ended September 30	
<i>(Canadian dollars in millions)</i>	2011	2010	2011	2010
Revenues				
Transmission	379	376	1,067	1,002
Distribution	990	970	2,998	2,795
Other	15	14	47	47
	1,384	1,360	4,112	3,844
Costs				
Purchased power	650	638	1,956	1,835
Operation, maintenance and administration	287	253	824	777
Depreciation and amortization	152	150	447	433
	1,089	1,041	3,227	3,045
Income before financing charges and provision for payments in lieu of corporate income taxes	295	319	885	799
Financing charges	88	82	258	255
Income before provision for payments in lieu of corporate income taxes	207	237	627	544
Provision for payments in lieu of corporate income taxes	40	19	106	52
Net income	167	218	521	492
Other comprehensive loss	-	-	-	-
Comprehensive income	167	218	521	492
Basic and fully diluted earnings per common share (Canadian dollars)	1.626	2.134	5.077	4.790

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

	Three months ended September 30		Nine months ended September 30	
<i>(Canadian dollars in millions)</i>	2011	2010	2011	2010
Retained earnings, beginning of period	2,624	2,046	2,354	1,791
Net income	167	218	521	492
Dividends (Note 3)	(42)	(4)	(126)	(23)
Retained earnings, end of period	2,749	2,260	2,749	2,260

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS (unaudited)

	Three months ended September 30		Nine months ended September 30	
<i>(Canadian dollars in millions)</i>	2011	2010	2011	2010
Accumulated other comprehensive loss, beginning of period	(10)	(10)	(10)	(10)
Other comprehensive loss	-	-	-	-
Accumulated other comprehensive loss, end of period	(10)	(10)	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

<i>(Canadian dollars in millions)</i>	September 30, 2011	December 31, 2010
Assets		
Current assets:		
Cash	-	33
Short-term investments	492	139
Accounts receivable (net of allowance for doubtful accounts)	919	911
Regulatory assets	31	42
Materials and supplies	22	21
Future income tax assets	25	35
Other	11	8
	<u>1,500</u>	<u>1,189</u>
Fixed assets:		
Fixed assets in service	20,336	19,767
Less: accumulated depreciation	<u>7,551</u>	<u>7,247</u>
	12,785	12,520
Construction in progress	1,720	1,394
Future use land, components and spares	<u>138</u>	<u>139</u>
	<u>14,643</u>	<u>14,053</u>
Other long-term assets:		
Regulatory assets	1,091	1,013
Deferred pension asset	465	460
Long-term investment	249	249
Intangible assets (net of accumulated amortization)	219	197
Goodwill	133	133
Future income tax assets	17	19
Other	<u>38</u>	<u>9</u>
	<u>2,212</u>	<u>2,080</u>
Total assets	<u>18,355</u>	<u>17,322</u>

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited) (continued)

	September 30, 2011	December 31, 2010
<i>(Canadian dollars in millions)</i>		
Liabilities		
Current liabilities:		
Bank indebtedness	20	-
Accounts payable and accrued charges	930	884
Regulatory liabilities	19	72
Accrued interest	122	84
Long-term debt payable within one year <i>(Note 4)</i>	250	500
	1,341	1,540
Long-term debt <i>(Note 4)</i>	7,903	7,278
Other long-term liabilities:		
Employee future benefits other than pension	1,031	980
Future income tax liabilities	766	693
Regulatory liabilities	634	540
Environmental liabilities	281	287
Asset retirement obligations	11	11
Long-term accounts payable and other liabilities	12	12
	2,735	2,523
Total liabilities	11,979	11,341
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	2,749	2,354
Accumulated other comprehensive loss	(10)	(10)
Total shareholder's equity	6,376	5,981
Total liabilities and shareholder's equity	18,355	17,322

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

	Three months ended September 30		Nine months ended September 30	
<i>(Canadian dollars in millions)</i>	2011	2010	2011	2010
Operating activities				
Net income	167	218	521	492
Environmental expenditures	(4)	(5)	(11)	(13)
Adjustments for non-cash items:				
Depreciation and amortization (excluding removal costs)	135	130	398	387
Regulatory asset and liability accounts	16	(24)	52	(31)
Gain on interest rate swaps	(3)	(4)	(9)	(13)
Future income taxes	(4)	2	(1)	15
Other	1	(1)	-	1
	308	316	950	838
Changes in non-cash balances related to operations	192	98	124	120
Net cash from operating activities	500	414	1,074	958
Financing activities				
Long-term debt issued	300	500	600	1,500
Long-term debt retired	-	-	(250)	(400)
Short-term notes payable	-	-	-	(55)
Dividends paid	(42)	(4)	(126)	(23)
Other	1	-	(1)	-
Net cash from financing activities	259	496	223	1,022
Investing activities				
Capital expenditures				
Fixed assets	(359)	(401)	(963)	(1,097)
Intangible assets	(23)	-	(59)	(9)
	(382)	(401)	(1,022)	(1,106)
Long-term investment	-	-	-	(250)
Other	10	12	25	31
Net cash used in investing activities	(372)	(389)	(997)	(1,325)
Net change in cash and cash equivalents	387	521	300	655
Cash and cash equivalents, beginning of period <i>(Note 6)</i>	85	108	172	(26)
Cash and cash equivalents, end of period	472	629	472	629

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles (GAAP) for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2010 which include information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Emerging Accounting Changes

United States (US) GAAP

The Company previously anticipated it would apply International Financial Reporting Standards (IFRS) to its consolidated financial statements for fiscal periods beginning on or after January 1, 2012, with comparative restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011. In the absence of a definitive plan for a new project to consider the issuance of a rate-regulated accounting standard by the International Accounting Standards Board, Hydro One began evaluating the option of adopting US GAAP in lieu of IFRS in the first quarter of this year. On July 7, 2011, the Company filed an application with the Ontario Securities Commission (OSC) for exemptive relief from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* that would otherwise require it to file consolidated financial statements based on IFRS starting with reporting periods commencing after January 1, 2012. The Company's application requested approval to instead adopt US GAAP, without becoming a Securities and Exchange Commission registrant, for its 2012, 2013 and 2014 fiscal years. On July 21, 2011, the OSC approved the Company's application and granted it the requested exemptive relief. Hydro One's Board of Directors has approved a resolution authorizing it to report under US GAAP. As a result, the Company's March 31, 2012 consolidated financial statements will be prepared based on US GAAP with two years of comparative restatement. The Company's opening US GAAP Consolidated Balance Sheet as at January 1, 2010 will be based on a retrospective application of US GAAP. The Company anticipates that its current application of Canadian GAAP for rate-regulated activities will generally be consistent with US GAAP. Any differences between Canadian and US GAAP and their impact on the Company's consolidated financial statements will be assessed as part of the Company's US GAAP conversion project.

3. DIVIDENDS

During the three months ended September 30, 2011, preferred dividends in the amount of \$4 million (2010 - \$4 million) and common dividends in the amount of \$38 million (2010 - \$nil) were declared. During the nine months ended September 30, 2011, preferred dividends in the amount of \$13 million (2010 - \$13 million) and common dividends in the amount of \$113 million (2010 - \$10 million) were declared.

4. LONG-TERM DEBT

During the nine months ended September 30, 2011, Hydro One issued additional notes under the Company's Medium-Term Note (MTN) Program.

On January 19, 2011, Hydro One issued additional 2.95% notes with a principal amount of \$250 million under its Medium-Term Note Program. These notes, which mature on September 11, 2015, were an additional offering of notes originally issued on September 13, 2010 for \$250 million. This additional issuance brings the total amount outstanding for this issue to \$500 million.

Hydro One entered into two fixed-to-floating interest-rate swaps, effective on January 19, 2011, each with a \$125 million notional principal amount, to convert the \$250 million notes issued on the same day into three-month variable-rate debt. The Company designated these swaps as fair value hedges of interest-rate risk. As such, changes in fair value are recognized in the Consolidated Statement of Operations for the period, as are changes in the fair value of the related fixed-rate notes. To the extent the hedge is ineffective, any ineffective amount is recorded immediately in financing charges within the Consolidated Statement of Operations. This amount was insignificant for the quarter and year-to-date periods.

On January 24, 2011, the Company issued \$50 million in floating-rate notes under its MTN Program with a maturity date of July 24, 2015.

On March 22, 2011, the Company entered into five forward-rate agreements to lock-in five interest-rate resets on the floating rate it pays on \$550 million of floating-rate debt, with respective settlement dates of: April 25, 2011; May 19, 2011; June 13, 2011; July 25, 2011; and August 19, 2011. On May 26, 2011, the Company entered into two more forward-rate agreements to lock-in one interest-rate reset on the floating rate it pays on \$250 million of floating-rate debt with a settlement date of September 12, 2011. On August 2, 2011, the Company entered into two more forward-rate agreements to lock-in two interest-rate resets on the floating rate it pays on \$50 million and \$115 million of floating-rate debt with settlement dates of October 24 and November 21, 2011. These agreements were classified as held-for-trading financial instruments and are measured at fair value. The cash settlements on the forward rate agreements that settled on July 25, August 19 and September 12 were insignificant. As at September 30, 2011, the net fair value loss recorded on the remaining two agreements was immaterial.

On September 26, 2011, the Company issued \$300 million 4.39% notes under its MTN program with a maturity date of September 26, 2041.

5. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

<i>(Canadian dollars in millions)</i>	Three months ended September 30		Nine months ended September 30	
	2011	2010	2011	2010
Pension				
Net periodic benefit cost	37	46	111	137
Pension fund contribution	38	30	116	89
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	15	12	45	36
Charged to results of operations	23	18	71	53
Employee Future Benefits Other than Pension				
Net periodic benefit cost	28	23	82	68
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	11	9	33	27
Charged to results of operations	17	14	49	41

6. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash", "short-term investments" and "bank indebtedness."

7. SEGMENT REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment, the operations of which primarily consist of those of the telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

<i>Three months ended September 30 (Canadian dollars in millions)</i>	Transmission	Distribution	Other	Consolidated
2011				
Segment profit				
Revenues	379	990	15	1,384
Purchased power	-	650	-	650
Operation, maintenance and administration	115	158	14	287
Depreciation and amortization	75	74	3	152
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	189	108	(2)	295
Financing charges				88
Income before provision for payments in lieu of corporate income taxes				207
Capital expenditures	210	172	-	382

2010				
Segment profit				
Revenues	376	970	14	1,360
Purchased power	-	638	-	638
Operation, maintenance and administration	90	147	16	253
Depreciation and amortization	72	76	2	150
Income before financing charges and provision for payments in lieu of corporate income taxes	214	109	(4)	319
Financing charges				82
Income before provision for payments in lieu of corporate income taxes				237
Capital expenditures	234	165	2	401

<i>Nine months ended September 30 (Canadian dollars in millions)</i>	Transmission	Distribution	Other	Consolidated
2011				
Segment profit				
Revenues	1,067	2,998	47	4,112
Purchased power	-	1,956	-	1,956
Operation, maintenance and administration	325	455	44	824
Depreciation and amortization	220	219	8	447
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	522	368	(5)	885
Financing charges				258
Income before provision for payments in lieu of corporate income taxes				627
Capital expenditures	571	450	1	1,022

HYDRO ONE INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited) (continued)

<i>Nine months ended September 30 (Canadian dollars in millions)</i>	Transmission	Distribution	Other	Consolidated
2010				
Segment profit				
Revenues	1,002	2,795	47	3,844
Purchased power	-	1,835	-	1,835
Operation, maintenance and administration	300	432	45	777
Depreciation and amortization	202	224	7	433
Income before financing charges and provision for payments in lieu of corporate income taxes	500	304	(5)	799
Financing charges				255
Income before provision for payments in lieu of corporate income taxes				544
Capital expenditures	638	465	3	1,106

<i>(Canadian dollars in millions)</i>	September 30, 2011	December 31, 2010
Total assets		
Transmission	10,228	9,805
Distribution	7,706	6,908
Other	421	609
	18,355	17,322

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

8. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the September 30, 2011 Consolidated Financial Statements.